Reservoir Simulation of CO_2 Storage in Deep Saline Aquifers

Presented by:

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Modeling Approach

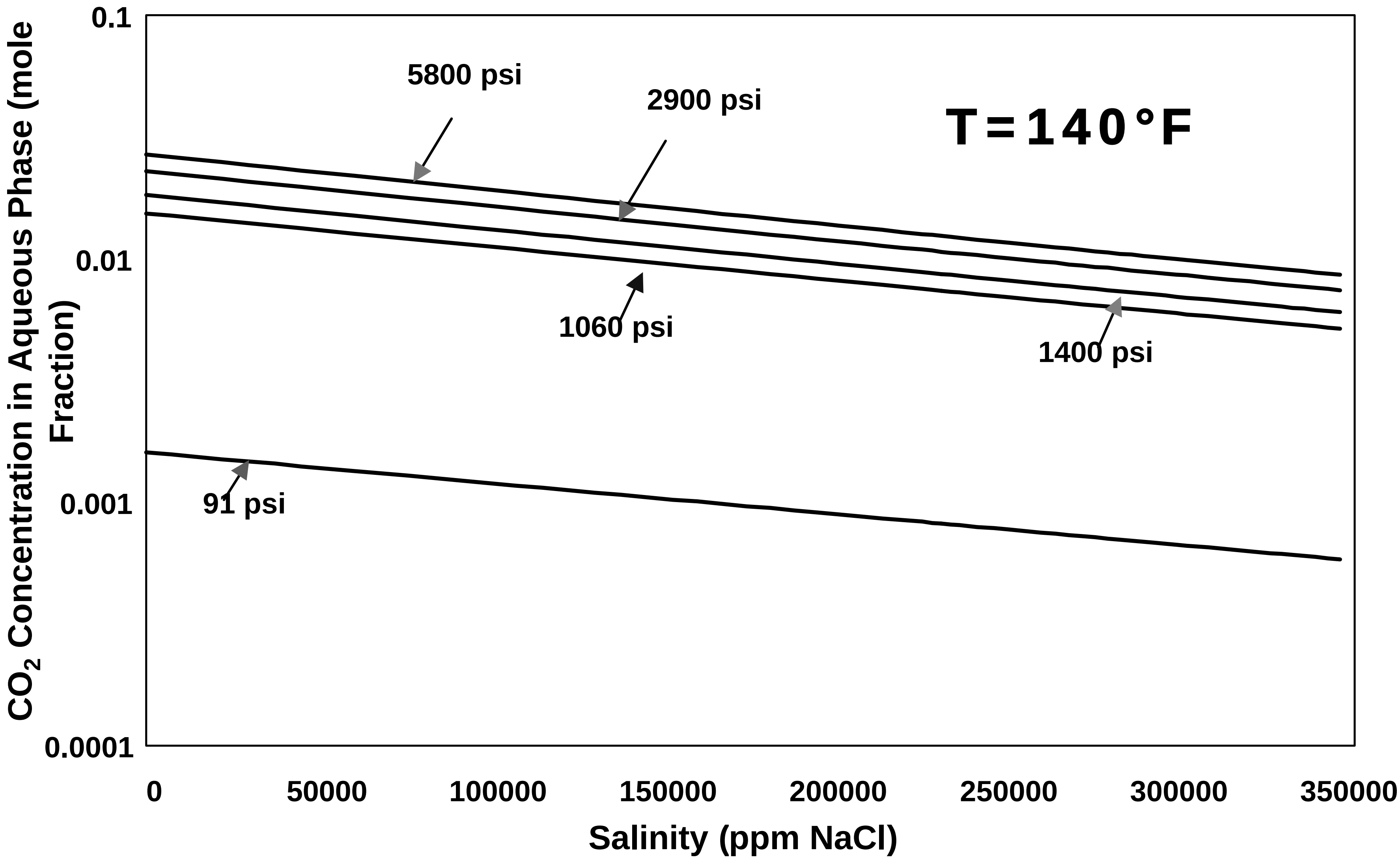
- Numerical compositional simulation
- Key processes
  - CO_2 / brine mass transfer
  - Multiphase flow
    - During injection *(pressure driven)*
    - After injection *(gravity driven)*
  - Chemical reactions
- Key outputs..CO_2 concentration in
  - Brine (as CO_3^{2-} and HCO_3^{-})
  - Gas (as CO_2)
  - Solid (as CO_3^{2-})

Method

- Obtain / parameterize physical property data
- Numerical simulations of storage scenario
  - 50 years CO_2 injection
  - 1000 years of gravity-driven fluid movement
  - GEM compositional simulator (CMG)
- Quantify storage in different sinks
  - CO_2-rich gas phase (residual saturation)
  - CO_2-saturated brine
  - Carbonate minerals

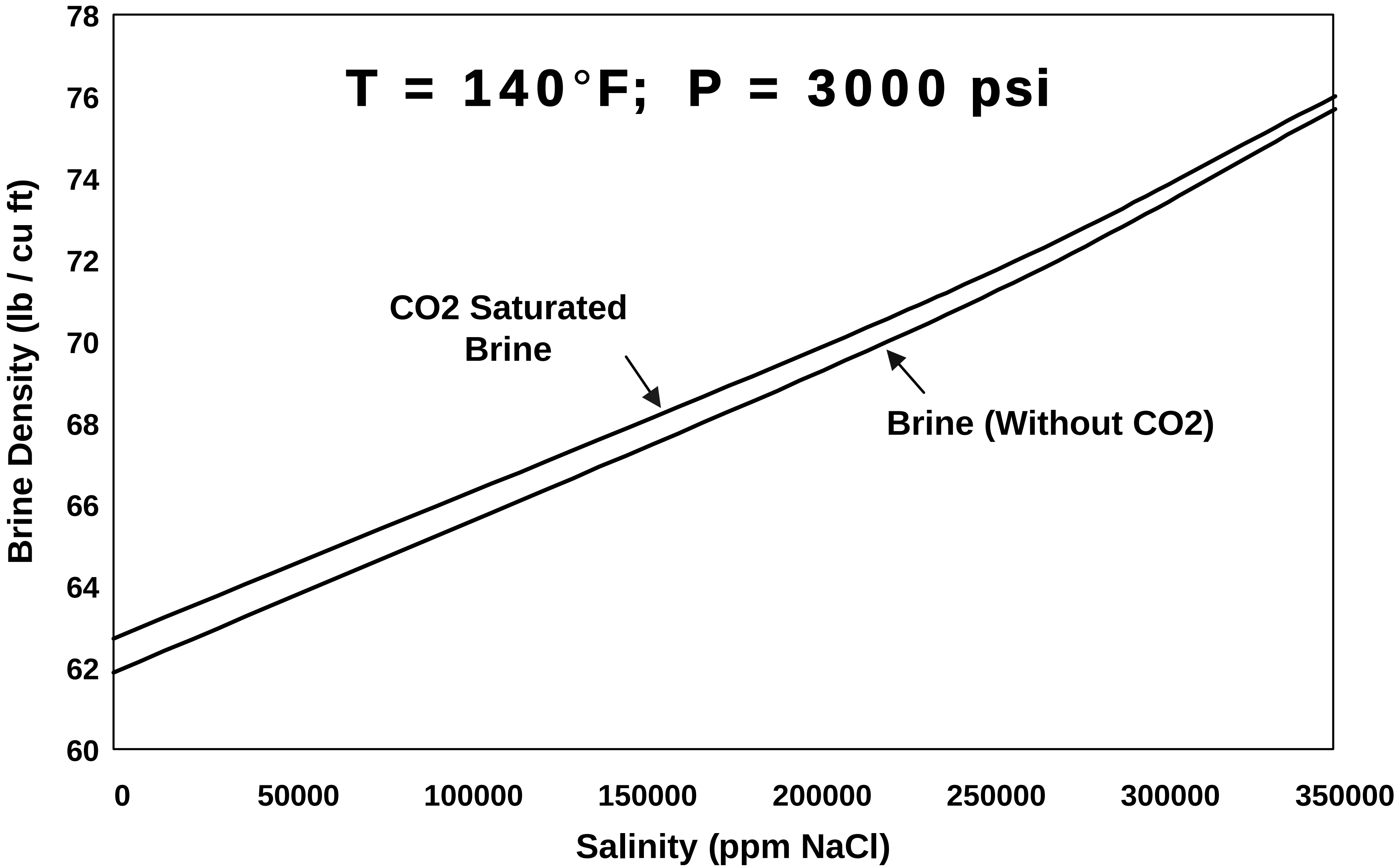
Key Physical Properties (1):

CO2 Solubility in Aqueous Phase



Key Physical Properties (2):

Density of CO_2-Saturated Brine



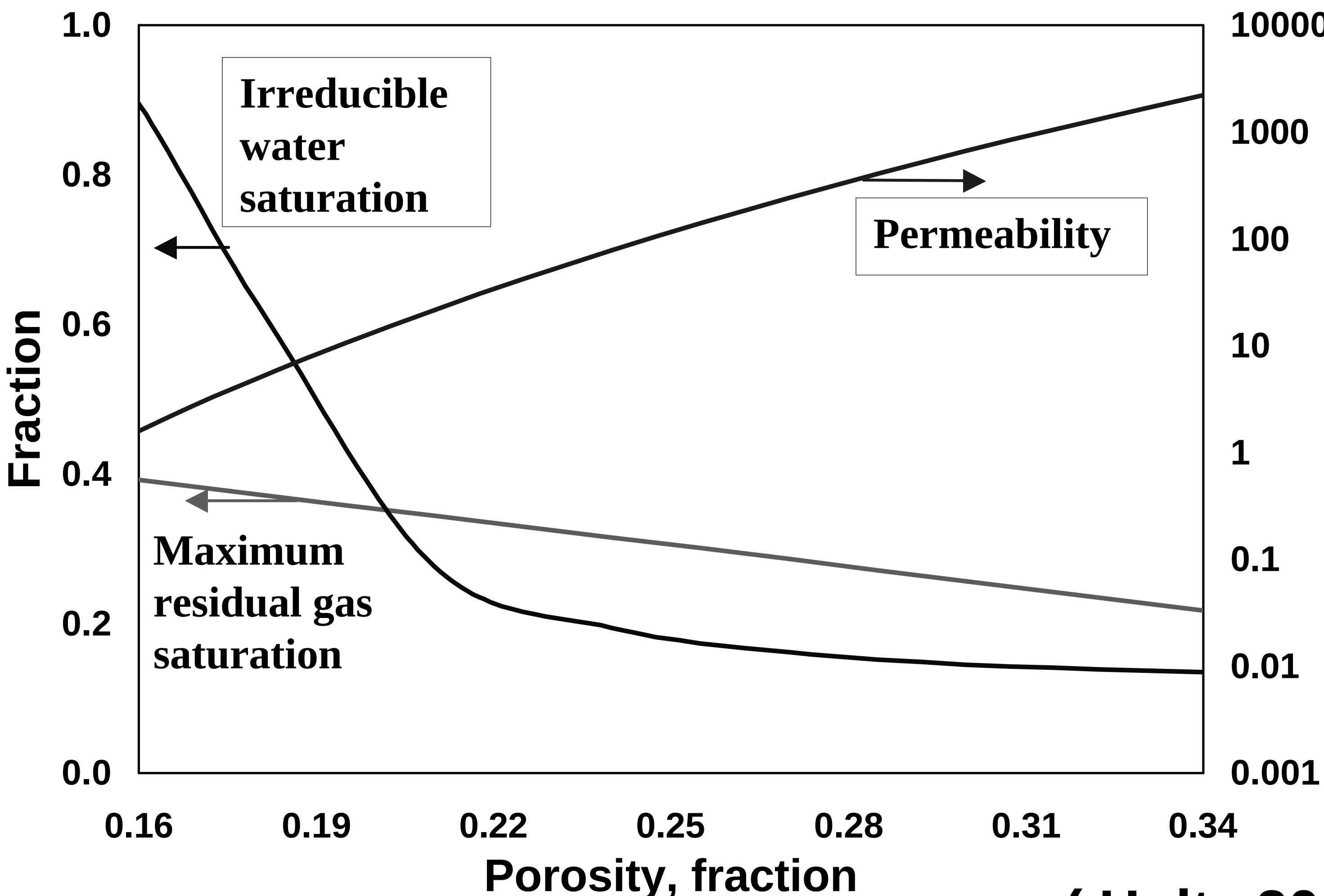
Effects of Physical Properties

- Shallow and high salinity aquifers will dissolve less CO_2 in aqueous phase than deep, low salinity aquifer
  - Salinity affects the distribution of CO_2 between various immobile phases in the order of 10% of total CO_2 injected
- After CO_2 injection ends, buoyancy continues to drive flow
  - Low density CO_2-rich gas will move up
  - High density brine containing dissolved CO_2 will sink

Key Petrophysical Properties

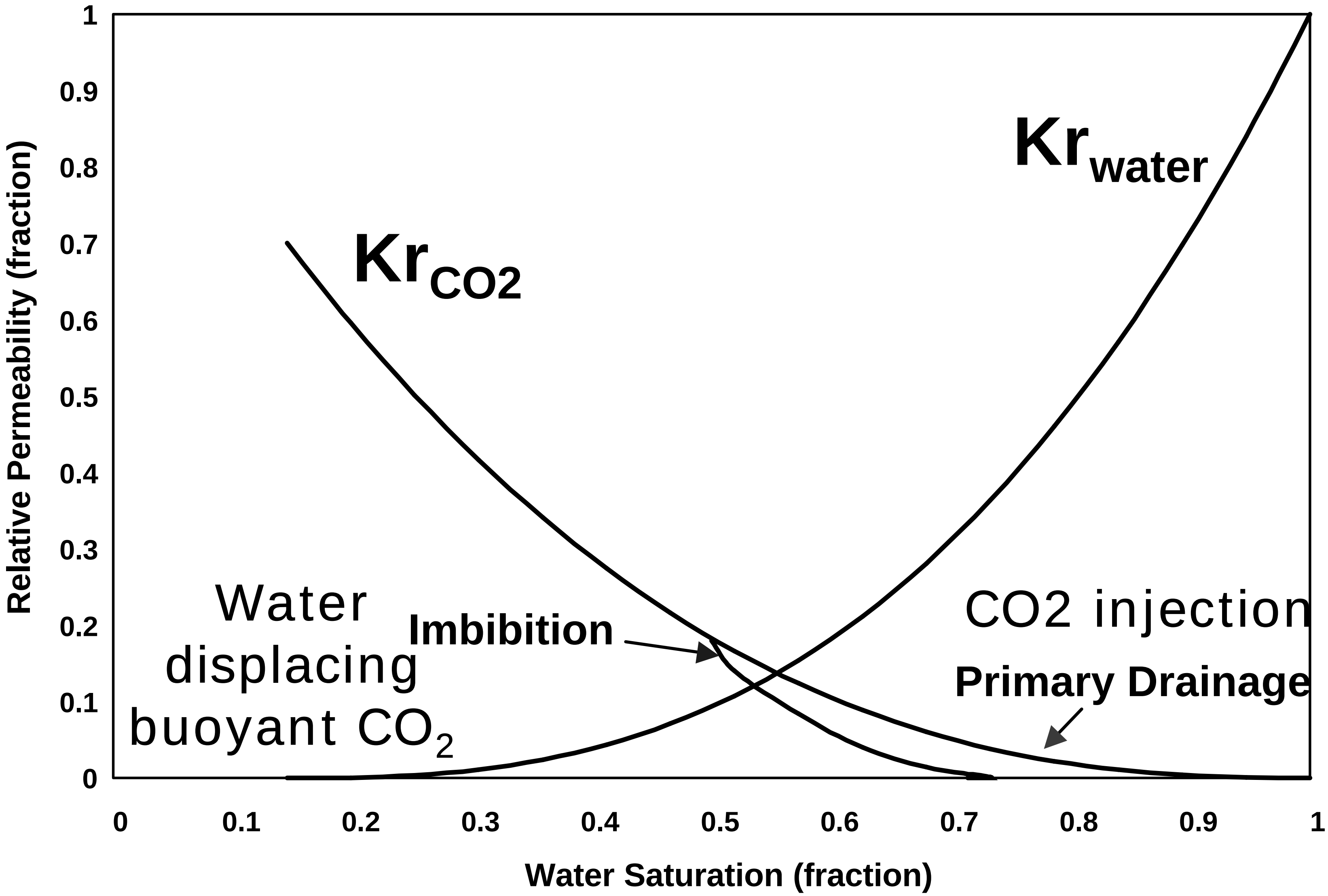
- Porosity
- Permeability
  - Magnitude
  - Anisotropy
- Residual gas saturation
  - Correlation with porosity (Holtz, 2002)
- Relative permeability
- Hysteresis
  - Land model

Correlation Between Various Aquifer Properties



- (Holtz 2002)

Hysteresis during Storage



Modeling Hysteresis with GEM for Gas Relative Permeability Curve

- **krg(Sg) = krg(Dr;Sg),during drainage;**
- **krg(Sg) = krg(Dr;Sg(shifted)), during imbibition;**

where

- **Sg(shifted)=(Sg-Sgrh)(Sgh)/(Sgh-Sgrh).**

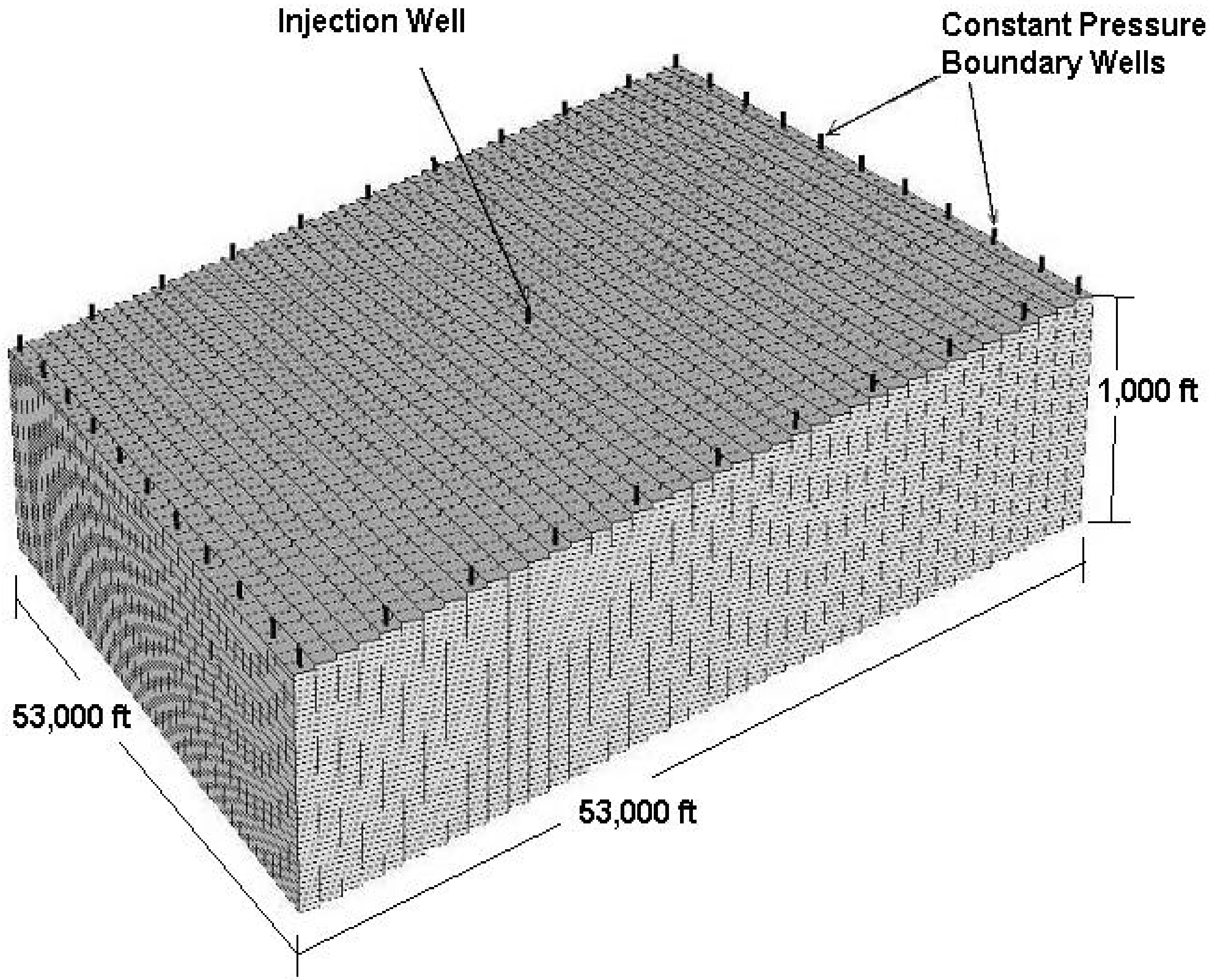
$$\frac{1}{S_{gr}^{\max}} - 1 = \frac{1}{S_{grh}} - \frac{1}{S_{gh}}$$

- **Sgh is the value of Sg when the shift to imbibition occurs**
- **Sgrh is the value of Sgr corresponding to Sgh via Land's equation**
- **Sgrmax is the user-entered parameter**

Curves

Base Case Simulation

Aquifer and Well Locations



Description of Base Case

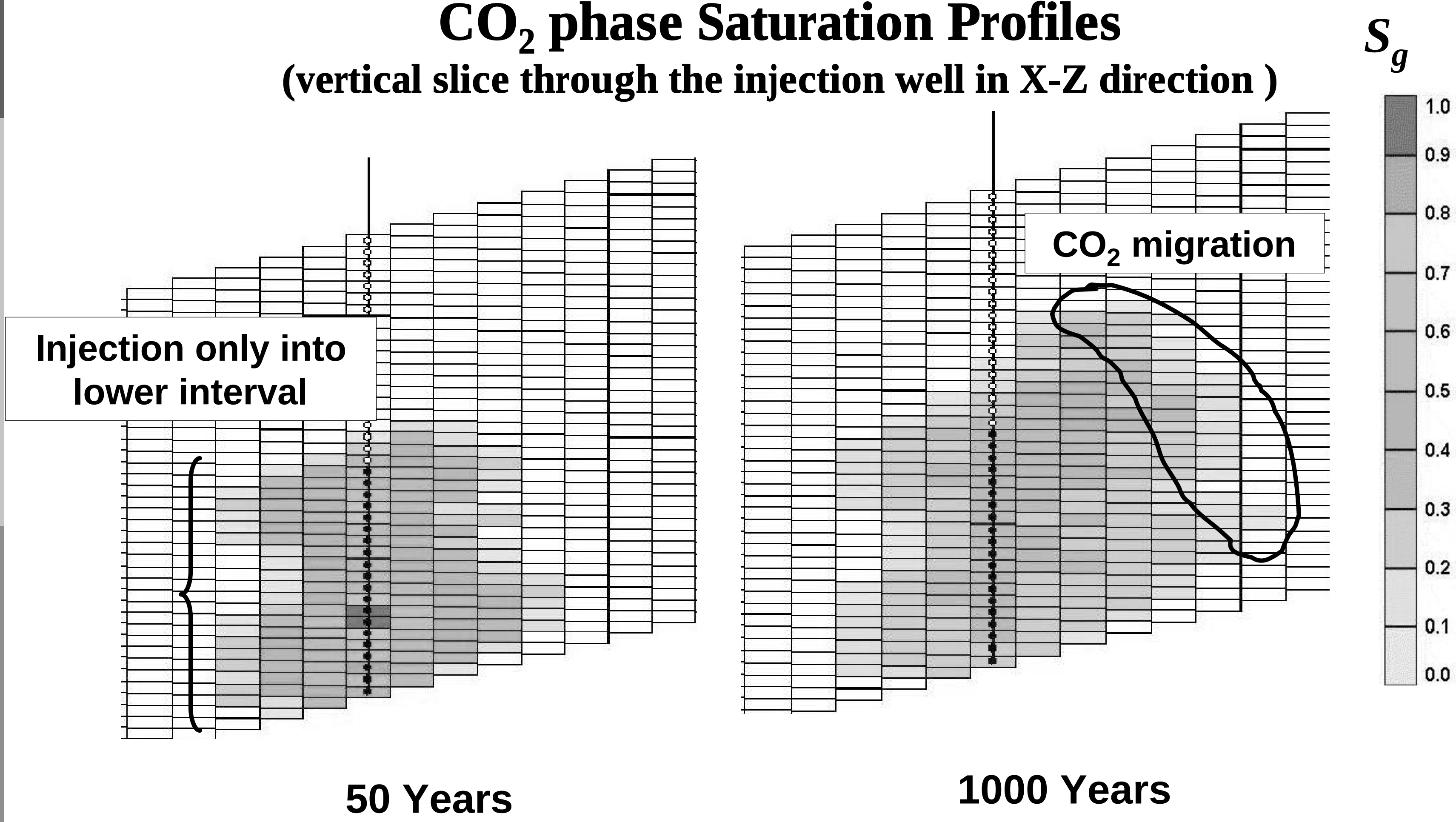
Aquifer Dimensions	**53,000 ft x 53,000 ft x 1000 ft**
Grid	**40 x 40 x 40**
Initial Pressure	**2265 psi**
Aquifer Temperature	**140 °F**
Mean Permeability	**100 md**
Permeability Ratio (K_v / K_h)	**0.001**
Dip	**1 degree**
Depth	**5300 ft**
Initial Water Saturation	**1.0**
Salinity	**100,000 ppm**
Maximum Injection Pressure	**3300 psi**
Maximum Injection Rate	**50 MMSCF/D**
Injection Time	**50 years**
Total Run Time	**1000 years**

Results:

Injection Strategy Limits Upward Migration

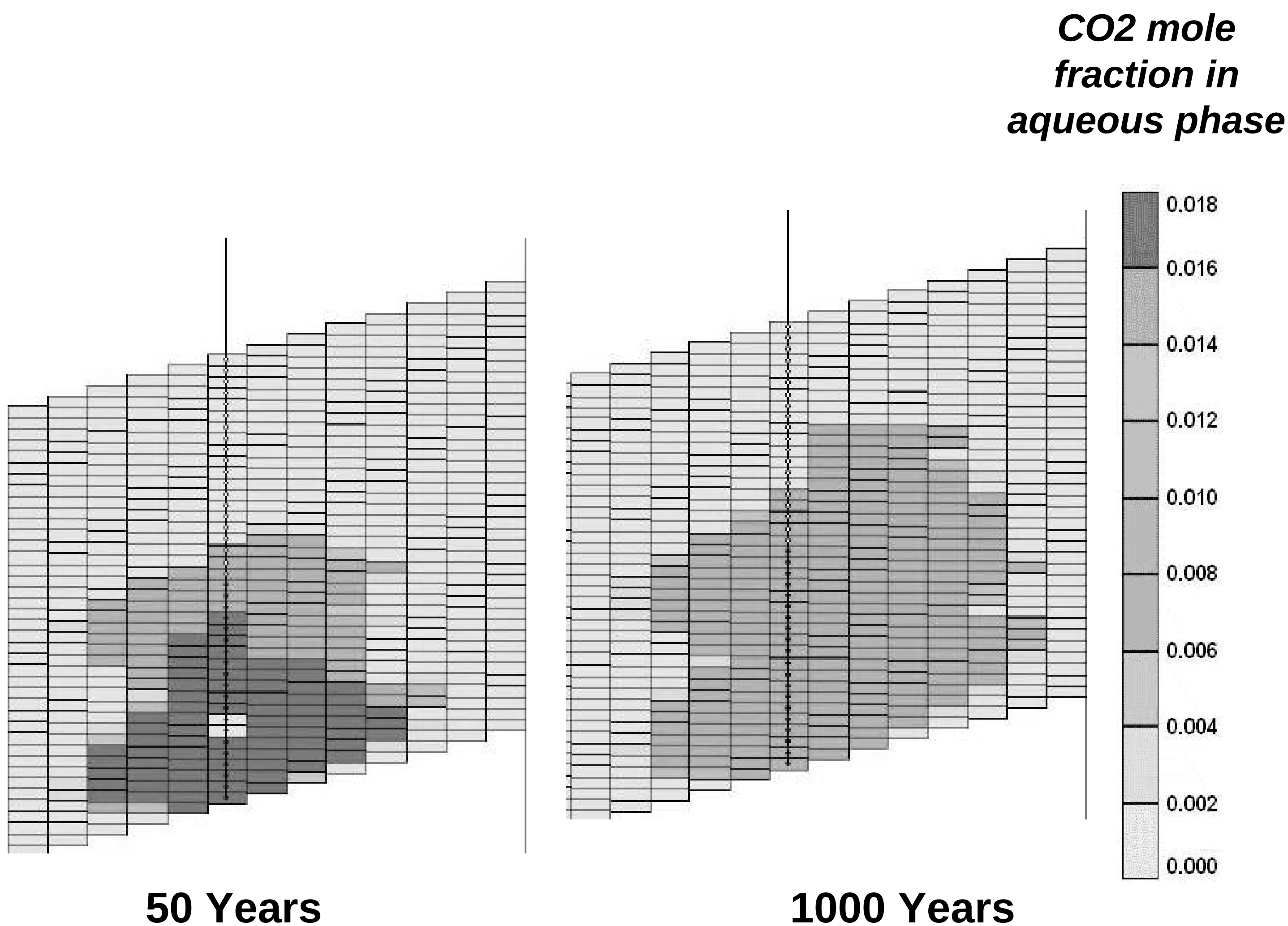
CO_2 phase Saturation Profiles

(vertical slice through the injection well in X-Z direction)



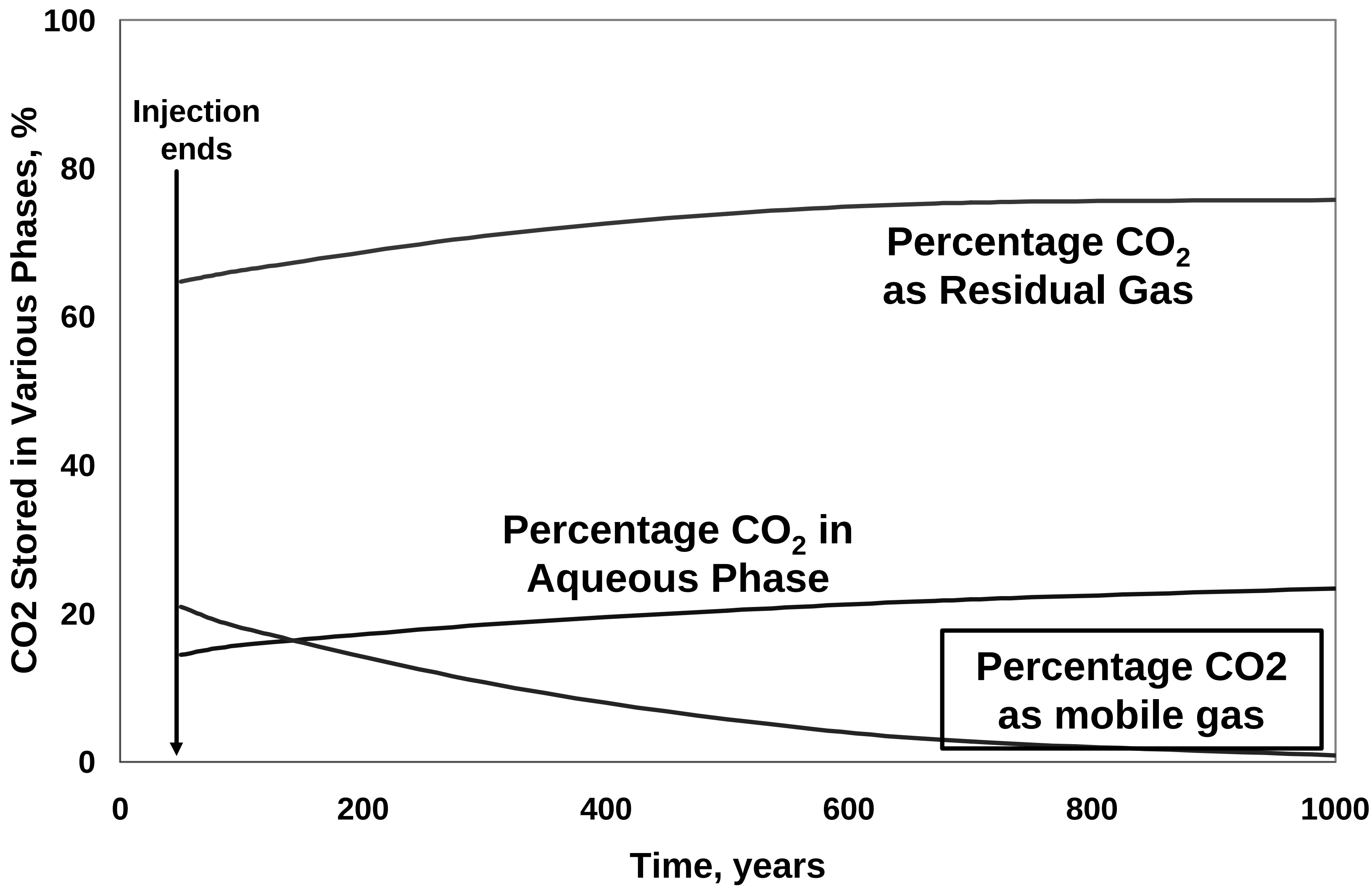
Results:

Brine Dissolution concentration migrates up-dip after injection



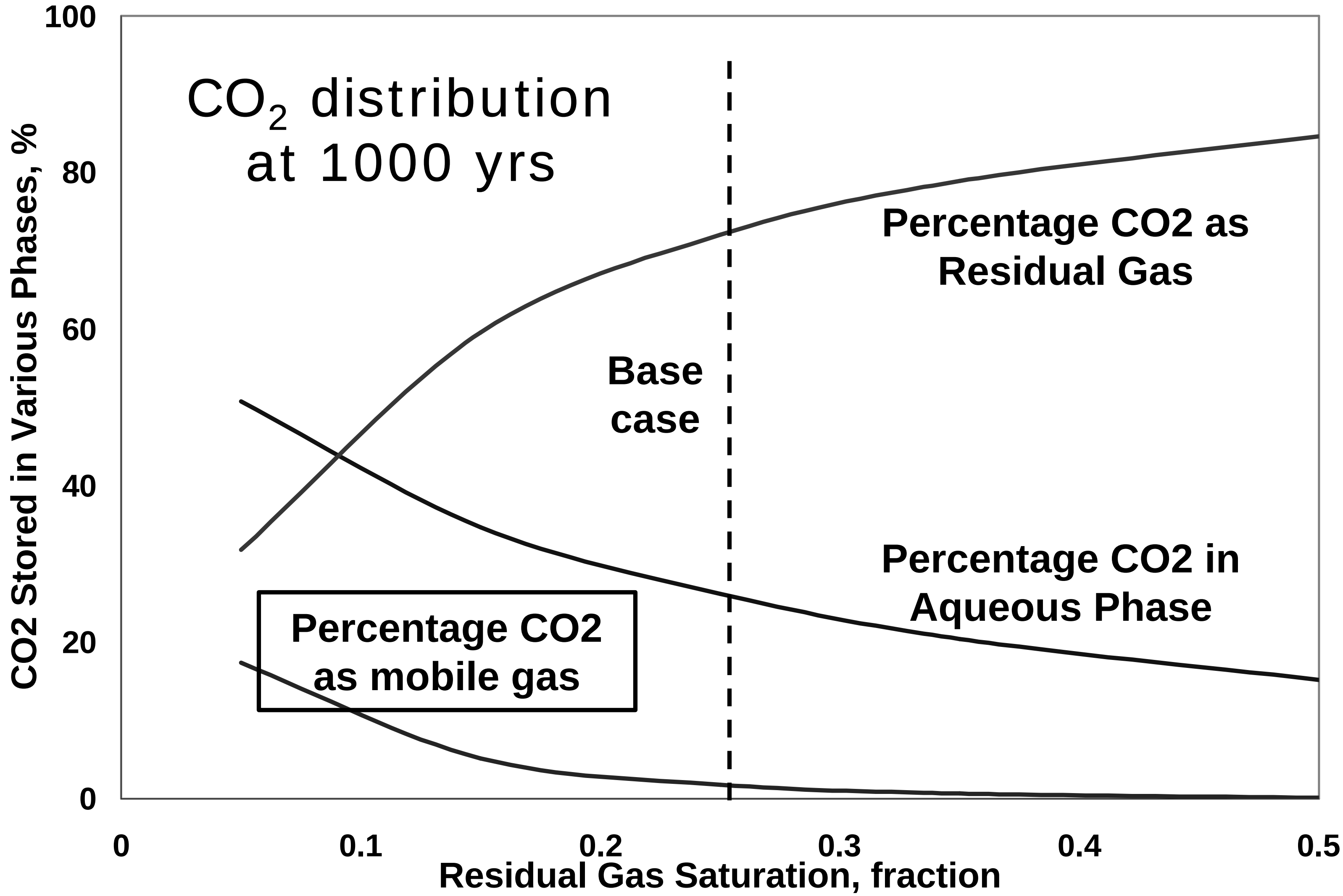
Key Findings (1):

The majority of CO_2 is stored as a residual phase



Key Findings (2):

Even low residual CO_2 saturation leads to residual phase as the dominant mechanism



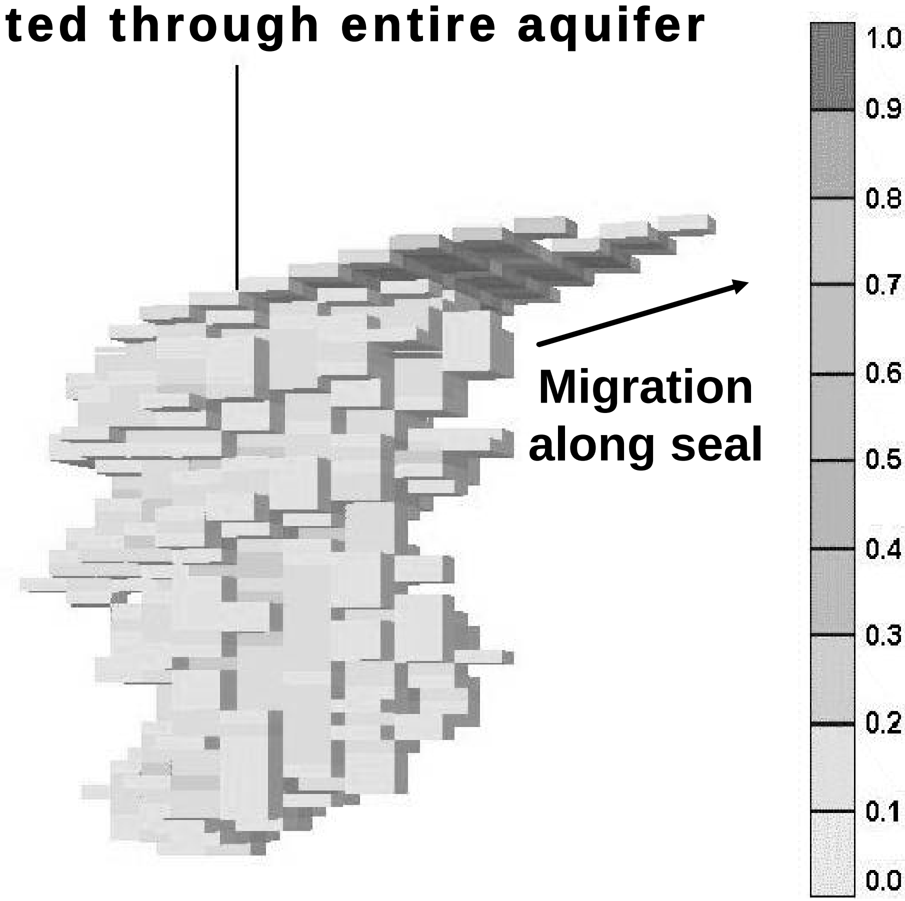
Key Findings (3): Well Completion Positioning Can Avoid Seal Integrity Issues

Completion scenario

- **Injection well completed through entire aquifer**

Result

- **Up-dip migration of injected CO2 for long distances**
- **Increased opportunity for leakage through formation top**



Summary and Conclusions

- After injection ends, capillary effects reduce the amount of mobile CO_2
  - Dissolution into brine
  - Gravity driven flow
- Time required to eliminate mobile CO_2 depends on petrophysical properties of aquifer
  - Residual gas saturation (Sgr)
  - Average permeability
  - Relative permeability (inc. hysteresis)
  - Anisotropy
- Gas migration is affected most by
  - Dip
  - Anisotropy

Summary and Conclusions

- Large fractions (>95%) of injected CO_2 can be immobilized in 1000 y
- Well completion design may significantly reduce the chances of leakage
- Potential leakage of gas through faults/fractures prior to trapping should be studied in more detail

Extra Slides

Tuning PR-EOS Parameters for CO2-Brine System

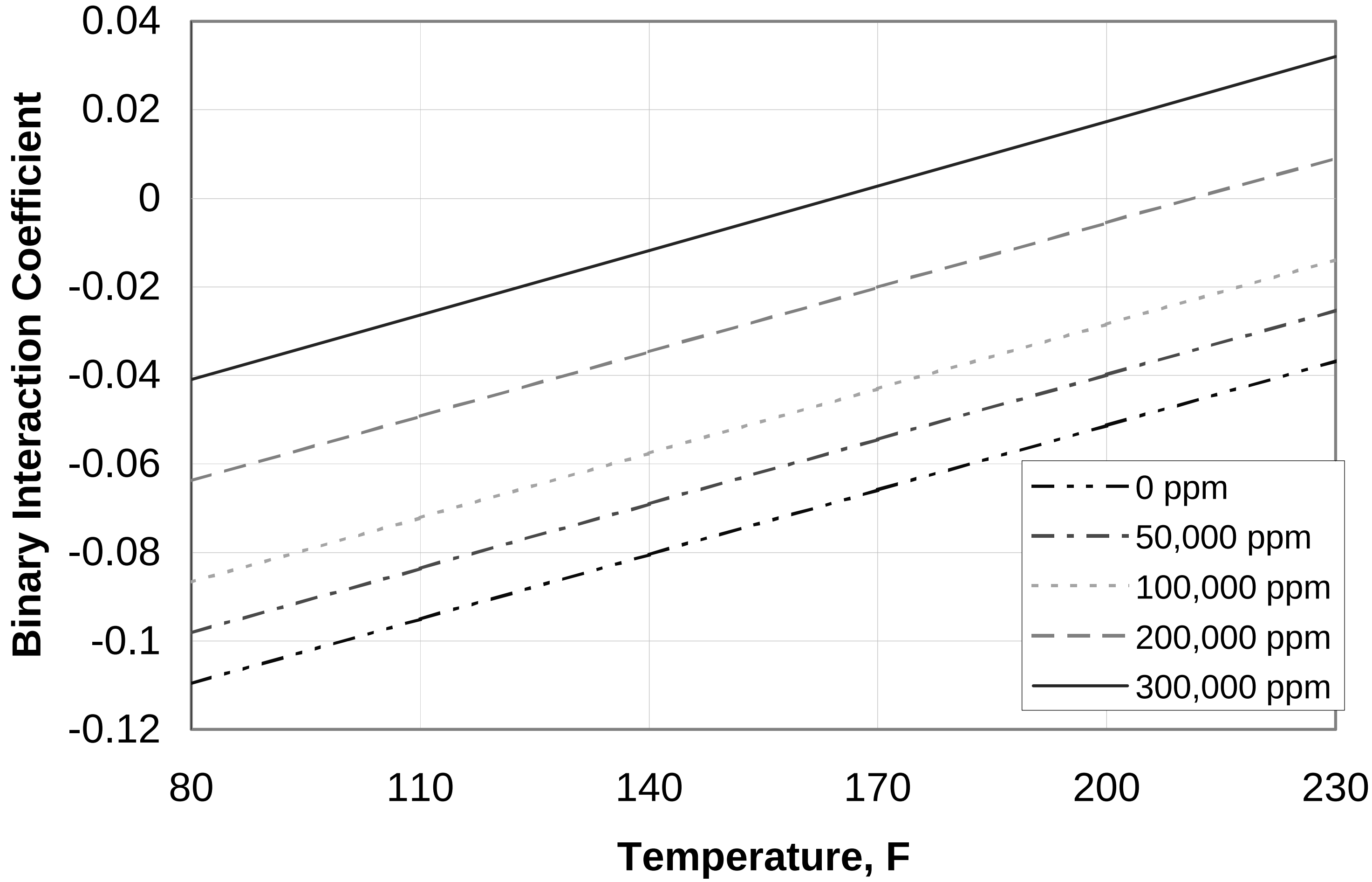
$$BIC_{H2O-CO2} = -0.093625 + (4.861E-4*(T-113)) + (2.29E-7*S)$$

$$VSP_{H2O} = 0.179 + (2.2222E-4*(T-113)) + (4.9867E-7*S)$$

- $BIC_{H2O-CO2}$ is Binary Interaction Coefficient for H2O-CO2 pair
- VSP_{H2O} Volume Shift Parameter for H2O
- T is temperature in degree Fahrenheit
- S is salinity of brine in ppm of NaCl

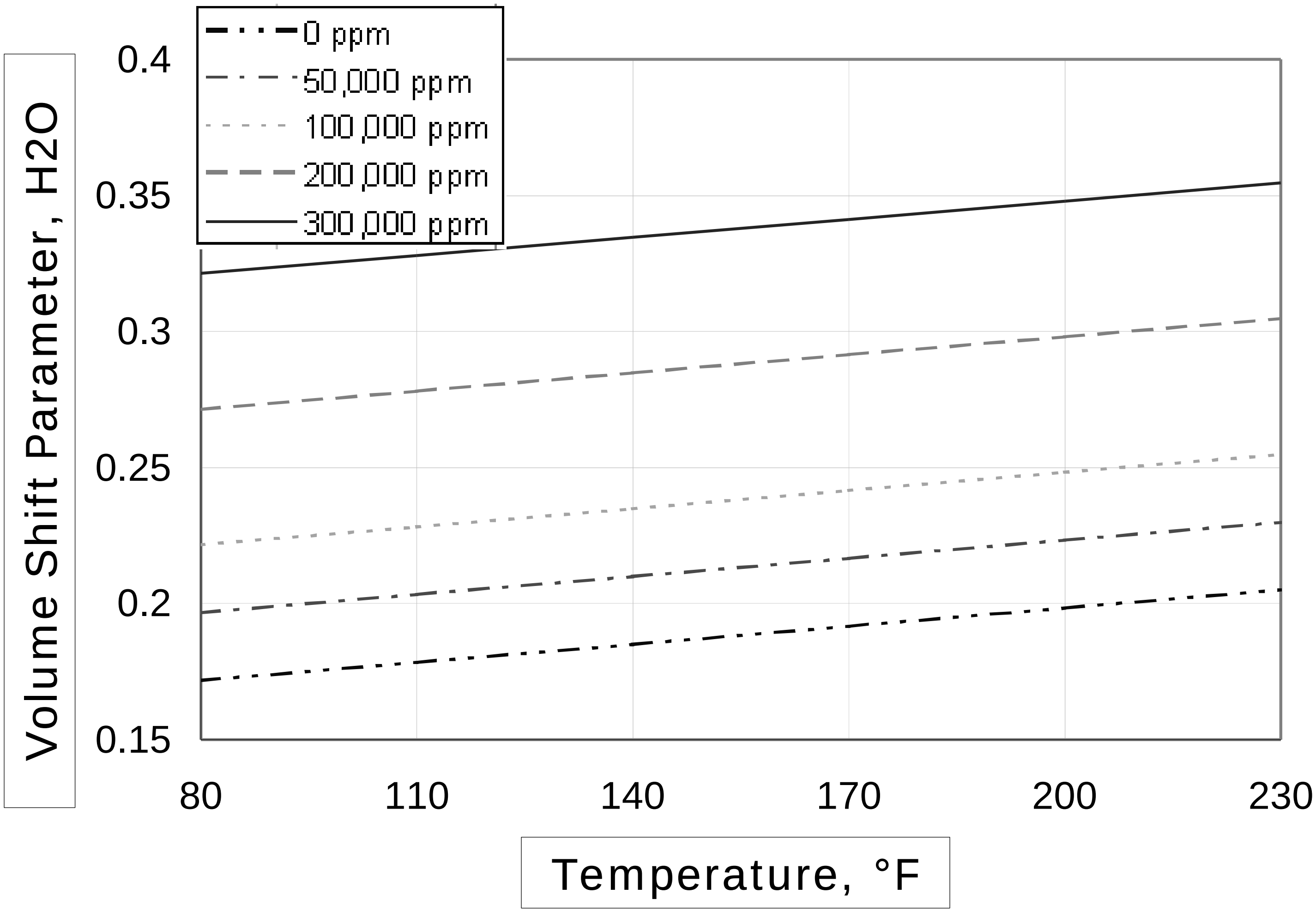
Tuning Binary Interaction Coefficient for H2O-CO2 pair

$$BIC_{H2O-CO2} = -0.093625 + (4.861E-4*(T-113)) + (2.29E-7*S)$$



Tuning Volume Shift Parameter for H2O

$$VSP_{H2O} = 0.179 + (2.2222E-4*(T-113)) + (4.9867E-7*S)$$



Plot